BEFORE THE
PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

IN THE MATTER OF:	**)**	
	)	
Application of Duke Energy Progress,	**)**	**DOCKET NO. 2018-318-E**
LLC for Adjustments in Electric Rate	**)**	
Schedules and Tariffs and Request for	**)**	
an Accounting Order	**)**	

Direct Testimony

of

JEFFRY POLLOCK

On Behalf of

Nucor Steel – South Carolina

March 4, 2019

J. POLLOCK
INCORPORATED

IN THE MATTER OF:	)	**DIRECT TESTIMONY OF**
	)	
Application of Duke Energy Progress, LLC for Adjustments in Electric Rate Schedules and Tariffs and Request for an Accounting Order	))))	**JEFFRY POLLOCK FOR** **NUCOR STEEL – SOUTH CAROLINA**

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GLOSSARY OF ACRONYMS

Term	Definition
CCOSS	Class Cost-of-Service Study
CFR	Code of Federal Regulations
CUR	Curtailable
DEP	Duke Energy Progress, LLC
DERP	Distributed Energy Resource Program
EDIT	Excess Deferred Income Taxes
FERC	Federal Energy Regulatory Commission
FPL	Florida Power & Light Company
FPSC	Florida Public Service Commission
GPC	Georgia Power Company
GPSC	Georgia Public Service Commission
kWh	Kilowatt-Hours
LGS	Large General Service
MW	Megawatts
NSP	Northern States Power
Nucor	Nucor Steel – South Carolina
PEF	Progress Energy Florida
PTY	Post-Test Year
RROR	Relative Rate of Return
SGS	Small General Service
TCJA	Tax Cuts and Jobs Act
TOU	Time-of-Use

Direct Testimony of Jeffry Pollock

1. INTRODUCTION, QUALIFICATIONS AND SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Jeffry Pollock; 12647 Olive Blvd., Suite 585; St. Louis, Mo., 63141.

Q. WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A. I am an energy advisor and President of J. Pollock, Incorporated.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. I have a Bachelor of Science Degree in Electrical Engineering and a Master's Degree in Business Administration, both from Washington University.

Upon graduation in June 1975, I joined Drazen-Brubaker & Associates, Inc. (DBA). DBA was incorporated in 1972 assuming the utility rate and economic consulting activities of Drazen Associates, Inc., which existed since 1937. From April 1995 to November 2004, I was a managing principal at Brubaker & Associates.

Over my career, I have been engaged in a wide range of consulting assignments regarding energy and regulatory matters. This includes preparing financial and economic studies of investor-owned, cooperative and municipal utilities on revenue requirements, cost of service and rate design, and conducting site evaluation. Recent engagements have also included advising clients on electric restructuring issues, assisting clients to procure and manage electricity in both competitive and regulated markets, developing and issuing requests for proposals (RFPs), evaluating RFP responses and contract negotiation.

I have worked on various projects in over 25 states and several Canadian provinces, and have testified before the Federal Energy Regulatory Commission, the Ontario Energy Board, and the state utility regulatory commissions of Alabama, Arizona, Arkansas, Colorado, Delaware, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Louisiana, Minnesota, Mississippi, Missouri, Montana, New Jersey, New Mexico, New York, Ohio, Pennsylvania, Texas, Virginia, Washington, and Wyoming. I have also appeared before the City of Austin Electric Utility Commission, the Board of Public Utilities of Kansas City, Kansas, the Board of Directors of the South Carolina Public Service Authority (a.k.a. Santee Cooper), the Bonneville Power Administration, Travis County (Texas) District Court, and the U.S. Federal District Court.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of Nucor Steel – South Carolina (Nucor).

Q. WHAT ISSUES ARE YOU ADDRESSING IN YOUR TESTIMONY?

A. First, I will provide a brief overview of DEP's Application. I will then discuss DEP's proposed:

- Class cost-of-service study (CCOSS);
- Class revenue allocation;
- Large General Service (LGS) rate design; and
- Depreciation expense.

Q. ARE OTHER WITNESSES ALSO TESTIFYING ON BEHALF OF NUCOR?

A. Yes. My colleague, Ms. Billie S. LaConte, will comment on DEP's proposed return on equity and equity ratio. She also addresses and proposes adjustments related to DEP's proposals on the following:

- Excess Deferred Income Tax (EDIT) Rider;
- Post-test year (PTY) plant adjustments;
- Amortization of coal ash pond closure expense;
- End-of-life nuclear materials and supplies; and
- The amortization of other regulatory assets.

Dr. Jay Zarnikau will address various issues including DEP's proposed Grid Modernization Plan and the treatment of litigation awards related to DOE's Yucca Mountain nuclear fuel storage project, along with also addressing potential rate increase impacts and the benefits of curtailable load.

Q. DOES THE FACT THAT YOU OR OTHER NUCOR WITNESSES ARE NOT ADDRESSING EVERY ISSUE RAISED IN THIS PROCEEDING IN ANY WAY IMPLY ACCEPTANCE OF ANY OF DEP'S PROPOSALS THAT ARE NOT ADDRESSED?

A. No.

Q. ARE YOU SPONSORING ANY EXHIBITS WITH YOUR TESTIMONY?

A. Yes. I am sponsoring **Pollock Exhibits 1** through **5** and **B-1** through **B-2**. These exhibits were prepared by me or under my direction and supervision.

Summary

Q. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.

A. My findings and recommendations are as follows:

- DEP's proposed increase should be cut by half based on our specific recommendations, in addition to any reduction in return on equity or common equity ratio as discussed in Ms. LaConte's testimony. The reduction should include the specific adjustments recommended by Ms. LaConte and a $7.5 million reduction in depreciation expense to amortize and return to consumers a $146.9 million surplus in DEP's accumulated depreciation reserve over a period not exceeding ten years as I recommend. Amortizing the surplus depreciation reserve is consistent with accepted regulatory practice and would help restore intergenerational equity.

- With one important exception, DEP's CCOSS uses appropriate and generally accepted methodologies for functionalizing, classifying, and allocating costs to customer classes that are also consistent with cost-causation principles.
- The Commission should require DEP to modify its CCOSS to properly account for the curtailable load that it serves. Presently, DEP's CCOSS allocates costs to classes as if curtailable loads were served entirely on a firm basis. The reality is that curtailable customers receive non-firm service. The revenues provided by the curtailable customers reflect the non-firm service that they receive. Accordingly, this mismatch between the revenues and allocated costs to curtailable customers distorts the CCOSS results, particularly for the LGS customer class. Specifically, DEP should allocate fixed production and transmission capacity costs using allocation factors that reflect the class contribution to firm peak coincident demand (and exclude non-firm demands). DEP should also use this approach in future rate cases.
- Correcting the CCOSS to properly recognize the non-firm nature of the service provided to curtailable customers would significantly impact the earned rate of return from the LGS class. Specifically, the LGS class would likely be shown as providing an above-average rate of return rather than a below-average rate of return as shown in DEP's filed CCOSS.
- Base revenues required from each customer class should reflect the actual cost of providing service to each customer class as closely as practicable. The reasons for adhering to cost-of-service principles are equity, engineering efficiency (cost-minimization), stability and conservation. Regulators sometimes limit the immediate movement to cost based on principles of gradualism and other factors.
- The proper way to measure the proposed base rate percentage revenue increases in this case is by removing all Rider 39 (fuel) and all other cost recovery clauses from current revenues. This is because adjustments to the cost recovery clauses occur independent of a general rate case. The base rate revenue increase proposed by DEP in this rate case has nothing to do whatsoever with increases in the costs that are separately recovered in the cost recovery clauses. DEP should also use this approach in future rate cases.
- DEP's proposed disparate percentage increases to the different LGS rate schedules are not justified (particularly after excluding cost recovery clause revenues such as fuel). Accordingly, each of the LGS rate schedules should see

the same percentage revenue increase when measured excluding cost recovery clause revenues.

2. BRIEF OVERVIEW OF DEP'S APPLICATION

Q. WHAT IS DEP PROPOSING AS TO RATE INCREASES IN THIS PROCEEDING?

A. DEP is seeking a three-step rate increase along with an offsetting tax credit rider. Step 1 is a $68.7 million base rate increase based on a calendar year 2017 test year. The Step 1 increase would be offset by a $10 million net credit under a proposed EDIT Rider in the first year. The $10 million includes a $12.5 million refund due to the Tax Cuts and Jobs Act (TCJA) that became effective on January 1, 2018, and a $2.5 million per year surcharge to accelerate recovery of $12.7 million of deferred Distributed Energy Resource Program (DERP) costs. The $12.5 million TCJA-related refund includes amortized federal income tax savings from January 1, 2018, through December 31, 2018, and the amortization of $210 million of EDIT. The EDIT balance is ratepayer-supplied capital; that is, ratepayers have funded EDIT through their electric rates in the past on the assumption that DEP would eventually use these funds to pay federal income taxes at a 35% tax rate. Under the TCJA, the federal corporate income tax rate was reduced to only 21%. As a result, this excess capital must be returned to ratepayers in a prompt and reasonable fashion.

DEP's initial Step 1 increase, along with the EDIT Rider, would result in a $58.7 million or 11.0% net revenue increase excluding certain recovery clause revenues (other than fuel). However, because fuel costs, like other pass-through costs, are determined separately and are not at issue in this case, the $58.7 million net base rate increase is actually a 16.2% increase, excluding Rider 39 (fuel) and other cost recovery clause revenues.

The Step 2 and 3 increases would recover $5.1 million and $5.8 million of additional revenue requirement associated with DEP's proposed Grid Improvement Plan beginning in June 2020 and June 2021, respectively.

Q. WHAT ARE THE MAJOR DRIVERS OF THE PROPOSED STEP 1 INCREASE?

A. Among the major cost drivers are:

- Plant additions since DEP's last rate case ($16 million);
- $176 million of post-test year plant additions ($22 million);
- Higher depreciation rates ($6 million);
- Additional expense for coal ash removal ($9.6 million);
- Recovery of other regulatory deferrals ($7 million); [1] and
- A request to accrue costs associated with nuclear materials and supplies that will purportedly be needed for decommissioning the Brunswick Units 1 and 2 (2036 and 2034, respectively), Harris (2046) and Robinson (2034) plants ($2.2 million).[2]

DEP's request also includes a 10.5% ROE with common equity representing 53% of its financial capital structure.

Q. SHOULD DEP'S REQUEST BE GRANTED?

A. No. As discussed in my testimony and in the testimony sponsored by other Nucor witnesses, DEP's proposed increase should be reduced by half, in addition to any reduction in the proposed return on equity or common equity ratio.

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[1] DEP Response to ORS Utility Rates Request 9-1. Some of the amounts in this response were revised in the Supplemental Testimony filed by DEP on January 22, 2019.

[2] DEP Corrected Supplemental Response to ORS 11th Audit Request, Item No. 11a (Jan. 17, 2019); Direct Testimony of David L. Doss, Jr., Doss Exhibit 2 at 39.

Q. WHY SHOULD DEP'S PROPOSED INCREASE BE REDUCED?

A. First, Ms. LaConte's testimony demonstrates that DEP's proposed 10.5% ROE and 53% equity ratio produce a cost of capital that is too high. Her testimony also recommends other specific adjustments to reduce DEP's proposed revenue requirement, including:

- Modifying the EDIT Rider to return excess tax dollars to consumers more quickly by amortizing all unprotected EDIT over a period not to exceed five years, amortizing the deferred revenue over two years, and denying the proposed DERP surcharge ($26.6 million of savings in year one instead of $9.9 million as proposed by DEP);
- Disallowing the proposed PTY plant adjustments (over $20 million of the revenue requirement) or, in the alternative, at least requiring DEP to update the accumulated depreciation balance of its test year net plant ($3 million savings) and the coal ash pond regulatory asset balance through December 2018 ($5 million);
- Amortizing coal ash pond closure expense over 20 years instead of 5 years ($7.1 million of annual savings if only coal ash expense through the test year is included);
- Disallowing DEP's proposed end-of-life nuclear cost adjustment ($2.2 million of annual savings); and
- Amortizing the Harris Nuclear Unit Nos. 2 and 3 Combined Operating License Application and Fukushima Daiichi Nuclear Power Station compliance costs over longer time periods ($1.5 million of annual savings).

In addition, as discussed in Part 6, I recommend a $7.5 million reduction to amortize and return to consumers a $146.9 million surplus in DEP's accumulated depreciation reserve over a period not exceeding ten years.

Q. HAVE YOU REVIEWED DEP'S CLASS COST-OF-SERVICE STUDY AND CLASS REVENUE ALLOCATIONS?

A. Yes. As discussed in Part 3, with one important exception, DEP's CCOSS uses appropriate and generally accepted methodologies for functionalizing, classifying, and allocating costs to customer classes that are also consistent with cost-causation principles.

The problem with the CCOSS is that the study allocates costs to all customer classes as if the entirety of their service is firm and there is no non-firm load. However, this a faulty premise. Specifically, DEP serves over 100 megawatts (MW) of curtailable load in South Carolina, almost all of which is the LGS customer class.[3] This is a large amount of this type of load in proportion to total DEP LGS class load and the South Carolina retail load, thereby emphasizing the effect of this flaw in the approach. As a result, DEP's CCOSS significantly overstates the cost to serve the LGS class while understating the corresponding cost to serve other customer classes. Since rate increases should generally be allocated in a manner consistent with the CCOSS results, this flaw needs to be corrected so the LGS class receives revenue increases consistent with its actual cost of service.

Q. IS DEP PROPOSING MAJOR CHANGES IN ITS INDUSTRIAL RATE DESIGN?

A. No. DEP is generally proposing to retain the status quo on the rate design applicable to most LGS customers. Although correct in principle, DEP's approach fails to accomplish this objective because, as discussed in Part 5, the proposed increases to each of the three LGS rate schedules vary substantially. Such a disparity of base rate increases within the LGS class is not reasonable under the circumstances. Each of the LGS rate schedules should see the same percentage increase in this case.

[3] The terms "interruptible," "curtailable," and "non-firm" all refer to the same type of load – DEP refers to this load as "curtailable".

3. CLASS COST-OF-SERVICE STUDY

Q. WHAT IS YOUR OPINION OF DEP'S CLASS COST-OF-SERVICE STUDY?

A. For the most part DEP's CCOSS generally comports with accepted industry practice and is a reasonable approach in this case to allocating costs among customer classes. For example, I support the coincident peak approach to production and transmission demand-related cost allocation and its proposed classification of distribution costs.

However, I do have a major concern about how non-firm curtailable load was treated. Specifically, DEP allocated demand-related costs as if each customer class takes 100% firm service, but the revenues assigned to each class reflect the lower quality of service provided to curtailable customers who properly pay lower rates (resulting in lower revenues for DEP) in return for DEP's ability to interrupt their operations. This mismatch between the revenue and costing assumptions seriously distorts the CCOSS results. Most of the curtailable load served in DEP's South Carolina service territory is in the LGS customer class resulting in the LGS class bearing the brunt of the mismatch. Therefore, I recommend that the Commission order DEP to revise its CCOSS so it properly recognizes the value of non-firm curtailable power and provides a more accurate measure of the cost to serve each customer class and, in particular, the LGS class.

<u>Background</u>

Q. WHAT IS A CLASS COST-OF-SERVICE STUDY?

A. A CCOSS is an analysis used to determine each customer class's responsibility for the utility's costs. Thus, it determines whether the revenues a class provides cover the class's cost of service. A CCOSS separates the utility's total costs into portions incurred on behalf of the various customer groups. Most of a utility's costs are incurred to jointly serve many customers. For purposes of rate design and class revenue allocation, customers are grouped into relatively homogeneous classes according to their usage patterns and service characteristics. The procedures typically used in a CCOSS are described in more detail in **Appendix A**.

<u>Treatment of Curtailable Load</u>

Q. WHAT IS CURTAILABLE POWER?

A. Curtailable power (also referred to as non-firm or interruptible power) is a tariff option that allows a utility to curtail designated non-firm load when resources are needed to maintain system reliability; that is, when there are insufficient generation and/or transmission resources to meet customer demand, a utility can curtail non-firm load. This allows the utility to maintain service to firm (*i.e.*, non-curtailable) loads and customers. Curtailable power, thus, is a lower quality of service than firm power.

Q. HOW DOES DEP'S PROPOSED CCOSS TREAT NON-FIRM CURTAILABLE LOAD?

A. DEP's CCOSS allocates costs based on these non-firm customer loads as if they were receiving entirely firm electricity service. That is, even though DEP can curtail the load of curtailable customers when capacity is needed to serve its firm customers, including at peak times if necessary, the proposed CCOSS allocates costs based on combined firm and non-firm demands at peak – thus these customers are allocated generation and transmission plant related costs based on the fiction that DEP provides firm (uninterrupted) service to these curtailable loads.

Q. SHOULD NON-FIRM CURTAILABLE LOAD BE TREATED AS FIRM LOAD IN A CLASS COST-OF-SERVICE STUDY?

A. No. This approach is simply not reasonable, particularly given the relatively large amount of curtailable load in DEP's South Carolina retail load. The Commission should require DEP to modify its treatment of curtailable load. From an operating perspective, this load is curtailable, unlike firm service, and it has been and is actually curtailed in order for DEP to continue serving its firm customers. Therefore, such non-firm loads have a lower cost and lower quality of service than firm loads. Further, the proposed CCOSS fails to recognize that DEP, not the customer, makes the decision whether, when, and how long to curtail non-firm load. Even if DEP does not curtail non-firm load on the system peak, the ability to interrupt that load if necessary provides the same capacity cost avoidance as if the customer were not operating at the system peak, along with other reliability benefits to DEP and other customers. Finally, the proposed treatment of non-firm load for cost allocation purposes is a departure from accepted regulatory practice in many jurisdictions where this issue has been addressed.

Q. PLEASE EXPLAIN WHY CURTAILABLE LOAD IS A LOWER QUALITY OF SERVICE COMPARED TO FIRM LOAD.

A. DEP can cut-off service to curtailable customers at any time when there is a system emergency or if there is not adequate capacity to serve firm customers. For example, DEP's Schedule LGS-CUR-TOU provides as follows:

> Company will specify a Curtailable Period when Company, in its opinion, does not have adequate capacity and reserves available to meet the anticipated customer requirements.[4] (emphasis added)

Because DEP has full control over whether to curtail non-firm load to alleviate a capacity shortage or to address some other system emergency, DEP does not and should not build or acquire capacity to serve curtailable customers. In short, curtailable customers take a lower quality of electric service because they have to stand ready to cut off their curtailable load at any time DEP deems it necessary to reliably serve firm customers.

Q. ARE THERE OTHER JURISDICTIONS THAT ALLOCATE DEMAND-RELATED COSTS BASED ON FIRM PEAK DEMANDS (EXCLUDING CURTAILABLE LOADS)?

A. Yes. The Federal Energy Regulatory Commission (FERC) has traditionally excluded interruptible load from the allocation of capacity-related costs. This long-standing practice is described in the following excerpt from a 2004 order rejecting Entergy's proposal to allocate capacity costs to interruptible load:

> 61. The Initial Decision overlooks that Entergy bases the recovery of its costs on the coincident peak recovery method, in which Entergy allocates its costs among its customers according to each customer's share of the System load at the time of the System peak. **It assesses its capacity costs to peak period users because it is peak demand that determines how much Entergy will invest in capacity.** [FN116] In Kentucky Utilities, the Commission explained the theory behind this method of cost allocation. A utility builds its bulk power facilities, i.e., generating units and transmission lines, to meet the maximum or peak demand of its firm customers. **Because the utility incurs the cost of these facilities to meet the peak demand of its firm customers, those customers should pay for the facilities. The peak responsibility method accomplishes this by allocating the cost of the facilities among the firm**

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[4] Duke Energy Progress, LLC, Large General Service – Curtailable Schedule LGS-CUR-TOU-52.

> **customers in the same proportion as each customer's demand bears to the system peak. [FN117] In contrast, as explained below, a utility need not build to meet its interruptible demand.**
>
> 62. The Commission thus traditionally has not "allocated" the cost of facilities to interruptible load…
>
> 63. Since Entergy can curtail interruptible service so that it does not contribute to the System peak, interruptible load does not determine how much Entergy must invest in capacity to meet the System peak, i.e., its customers' needs. Therefore, under the peak load responsibility cost allocation method, Entergy should not include interruptible load in its calculations.
>
> 67. Thus, as explained above, because Entergy did not and does not have to construct capacity to serve interruptible load at the time of its System peak (and thus can and does offer interruptible service at a lower rate), the Initial Decision cannot stand. [FN121] Moreover, the cost recovery system that the Initial Decision adopts [FN122] is without foundation. There is no evidence that Entergy built capacity to serve interruptible load. While Entergy may have considered interruptible capacity in its planning before 1995, [FN123] it then already had sufficient capacity to meet its load and did not need to construct additional capacity; its most recent capacity additions occurred in the mid-1980's. [FN124] So reference to interruptible load in Entergy's planning documents does not demonstrate that Entergy actually built capacity to serve interruptible load. [FN125]
>
> 69. Also, it is uncontroverted that Entergy does not now acquire capacity, and, since at least 1995 has not acquired capacity, to serve interruptible loads. [FN131] The Presiding Judge so found, [FN132] and no one disputes this finding. [FN133] Since it is clear, then, that firm load currently drives Entergy's capacity acquisitions, there is no credible basis to allocate the cost of capacity to interruptible loads that existed in 1995. For example, in 2000, Entergy needed all of its existing generating capacity, plus 2950 MW, to meet firm load. [FN134] When all capacity is needed to serve firm load, there is no logical reason to allocate the cost of this capacity based, in part, on interruptible load - - either pre-1995 or post-1995.[5]

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[5] *Louisiana Pub. Serv. Comm'n & the Council of the City of New Orleans v. Entergy Corp. Entergy Services, Inc. Louisiana Pub. Serv. Comm'n*, 106 FERC ¶ 61228 (F.E.R.C. Mar. 8, 2004) (emphasis added).

Q. ARE YOU AWARE OF OTHER UTILITIES THAT ALSO ADJUST THEIR CLASS COST-OF-SERVICE STUDIES TO RECOGNIZE CURTAILABLE SERVICE?

A. Yes. Several utilities that serve significant amounts of non-firm load make specific adjustments to their respective CCOSSs to recognize the non-firm nature of these loads.

Q. HOW SHOULD CURTAILABLE LOAD BE TREATED IN THE CLASS COST-OF-SERVICE STUDY?

A. Capacity costs should be allocated based on firm peak demand and should not be allocated based on curtailable demands because curtailable load does not cause such costs to be incurred. This would be accomplished by excluding curtailable load from the demand allocation factors in the CCOSS, as if the load were curtailed, and the allocation factors would then only reflect firm coincident peak loads.

Q. HOW WOULD ADJUSTING FOR CURTAILABLE LOAD AFFECT THE RESULTS OF DEP'S CLASS COST-OF-SERVICE STUDY?

A. I have prepared an illustration in **Appendix B**, to demonstrate the impact of properly recognizing curtailable load in DEP's CCOSS. The impact is summarized in **Table 1**.

Table 1
Illustration Showing the Impact of Properly Recognizing Curtailable Service in a CCOSS

Customer Class	RROR Per DEP	RROR Restated
Residential	66	55
Small General Service	63	51
Small General Service: CLR	12	5
Medium General Service	170	154

Table 1 Illustration Showing the Impact of Properly Recognizing Curtailable Service in a CCOSS		
Customer Class	**RROR Per DEP**	**RROR Restated**
Large General Service	78	128
Seasonal & Intermittent	220	212
Traffic Signal Service	(123)	(129)
Area Lighting Service	430	430
Street Lighting Service	11	11
Sports Field Service	588	588

As **Table 1** illustrates, adjusting the CCOSS to properly recognize curtailable service can completely flip the results for the LGS class. Specifically, under DEP's CCOSS with no recognition of curtailable service, the class earned a 78 RROR. Correcting the study to recognize the estimated impact of curtailable service in this illustration would raise the RROR to 128. In other words, a more appropriate CCOSS could show that the LGS class is currently providing revenues well in excess of its allocated costs.

Q. WHAT IS THE SIGNIFICANCE OF THE RROR?

A. The RROR measures whether a customer class is currently providing revenues that are above cost (*i.e.,* RROR above 100), below cost (*i.e.,* RROR below 100) or at cost (*i.e.,* RROR equals 100) according to the CCOSS. Of course, if the CCOSS does not accurately reflect cost causation, then the RRORs will not provide accurate guidance, as in the case of DEP's proposed CCOSS.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that the Commission require DEP to revise its CCOSS to properly recognize curtailable service by basing the demand allocation factor on firm peak demand. Ideally such a change will be made in this case and the results of the revised CCOSS used to determine appropriate revenue increases. However, at a minimum, DEP should be required to reflect this improvement in the CCOSS filed in future rate cases. This will ensure that the CCOSS results are appropriately interpreted for those customer classes that have curtailable service (*i.e.,* SGS and LGS). Further, if the revised CCOSS shows that the LGS class would be above cost if DEP's CCOSS had properly recognized curtailable service, this finding can be considered in determining how any base revenue increase should be spread among the various customer classes (*i.e.,* class revenue allocation).

4. CLASS REVENUE ALLOCATION

Q. WHAT IS CLASS REVENUE ALLOCATION?

A. Class revenue allocation is the process of determining how any base revenue change the Commission approves should be spread to each customer class the utility serves.

Q. HOW SHOULD ANY CHANGE IN BASE REVENUES APPROVED IN THIS DOCKET BE SPREAD AMONG THE VARIOUS CUSTOMER CLASSES DEP SERVES?

A. Base revenues should reflect the actual cost of providing service to each customer class as closely as practicable, typically reflecting the results of a reasonable CCOSS. Regulators sometimes limit the immediate movement toward cost based on principles of gradualism, rate administration and other factors.

Q. PLEASE EXPLAIN THE PRINCIPLE OF GRADUALISM.

A. *Gradualism* is a concept that is applied to prevent a class from receiving an overly-large percentage rate increase. That is, the movement to cost of service should be made gradually rather than all at once because it would result in rate shock to the affected customers.

Q. ARE THERE OTHER REASONS TO APPLY COST-OF-SERVICE PRINCIPLES WHEN CHANGING RATES?

A. Yes. Some other reasons for adhering to cost-of-service principles include equity, engineering efficiency (cost-minimization), stability and conservation.

Q. WHY ARE COST-BASED RATES EQUITABLE?

A. Rates which primarily reflect cost-of-service considerations are equitable because each customer pays what it actually *costs* the utility to serve the customer – no more and no less. If rates are not based on cost, then some customers must pay part of the cost of providing service to other customers, which is inequitable.

Q. HOW DO COST-BASED RATES PROMOTE ENGINEERING EFFICIENCY?

A. With respect to engineering efficiency, when rates are designed so that demand and energy charges are properly reflected in the rate structure, customers are provided with the proper incentive to minimize their costs, which will, in turn, minimize the costs to the utility.

Q. HOW CAN COST-BASED RATES PROVIDE STABILITY?

A. When rates are closely tied to cost, the utility's earnings are stabilized because changes in customer usage patterns result in parallel changes in revenues and expenses.

Q. HOW DO COST-BASED RATES ENCOURAGE CONSERVATION, REDUCED PEAK DEMANDS AND DEMAND RESPONSE?

A. By providing fair, balanced and reasonable price signals against which to make consumption decisions, cost-based rates encourage conservation (of both peak day and total usage), which is properly defined as the avoidance of wasteful or inefficient use (not just *less use*).

Q. HOW IS DEP PROPOSING TO ALLOCATE THE PROPOSED BASE REVENUE INCREASE IN THIS PROCEEDING?

A. DEP's proposed base revenue increase is shown in **Pollock Exhibit 1**. It shows DEP's proposed allocation of the $58.7 million net base revenue increase relative to present revenues, excluding all cost recovery clauses except fuel.

As can be seen, DEP's proposal translates into an 11.0% base revenue increase on this basis. The increases to specific customer classes would range from a 5.2% reduction for Sports Field Lighting service to a 28.8% increase for Traffic Signal service.

Q. DOES DEP'S PROPOSAL AS SHOWN IN POLLOCK EXHIBIT 1 ACCURATELY MEASURE THE IMPACT OF THE PROPOSED RATE INCREASE?

A. No. DEP is seeking an increase in base rates and not an increase in any of the various cost recovery clauses, including Rider 39 (fuel). These cost recovery clauses are addressed in separate proceedings and are unrelated to DEP's proposal to increase base rates. In other words, the proposed base revenue increase has nothing to do whatsoever with changes in DEP's cost recovery clauses (including fuel). Thus, including any cost recovery charges in the analysis precludes accurately measuring the proposed base revenue increase, which is designed to recover increases in costs other than the costs recovered in the various cost recovery clauses.

Q. WERE REVENUES FROM ALL COST RECOVERY CLAUSES REMOVED IN POLLOCK EXHIBIT 1?

A. No. While DEP removed revenues from certain cost recovery clauses, the present base revenues shown in column 1 of **Pollock Exhibit 1** include revenues collected in

Rider 39. Rider 39 recovers fuel, variable environmental, avoided capacity costs and distributed energy resource program costs. As with DEP's other cost recovery clauses, Rider 39 is adjusted outside of a base rate case in a separate proceeding and thus fuel revenues should also be removed from the calculation.

Q. PLEASE ELABORATE FURTHER ON EXCLUDING FUEL.

A. When looking at the magnitude of the overall base rate increase or the fairness of percentage rate increases to various classes or rate schedules, it is important to remove large extraneous revenues and costs (like fuel) in order to focus on the actual base rate revenue requirement that is at issue and subject to increase in the proceeding. This is particularly important for industrial rates, where a larger percentage of the total rate is fuel.

DEP witness Ward's testimony effectively supports this conclusion. As she states, "…the Company's requested increase in revenues in this case is related to non-fuel revenues. There will be no change to customers' bills as a consequence of inclusion of these fuel cost factors in the Company's proposed base rates. The Company will continue to bill customers the fuel rates authorized by the Commission in its annual fuel proceedings."[6] She further explains how she developed pro forma adjustments that were "…needed to eliminate the impact of fuel, fuel-related and DERP charges in this rate case."[7] If fuel rates are not affected by the base rate increase, then they should not be considered when determining the percentage revenue increases.

[6] Direct Testimony of Kendra A. Ward at 5-6.

[7] *Id*. at 7.

Q. WHAT WOULD BE THE PROPOSED INCREASES IF THEY ARE RESTATED TO EXCLUDE RIDER 39 (FUEL), IN ADDITION TO THE OTHER COST RECOVERY CLAUSES DEP PROPERLY EXCLUDED?

A. **Table 2** below shows my estimate of DEP's proposed increase measured as a percent of present base revenues *excluding* revenues from Rider 39 and other clauses for selected customer classes/rates.

Table 2
Proposed Net Base Rate Increase
Excluding Rider 39 and
Other Cost Recovery Clauses

Customer Class	Amount (000)	Percent
Residential	$30,292	19.7%
Small General Service	$4,937	20.4%
Medium General Service	$9,800	10.4%
Large General Service	$12,333	16.9%
Seasonal & Intermittent	$125	8.1%
Total Lighting	$1,170	7.2%
Total	$58,657	16.2%

As **Table 2** demonstrates, DEP's proposed $58.7 million base revenue increase is actually a 16.2% increase relative to present base revenues, excluding all clause revenues (such as Rider 39 fuel and other costs).

Q. IS DEP'S PROPOSED CLASS REVENUE ALLOCATION GENERALLY CONSISTENT WITH THE CLASS COST-OF-SERVICE STUDY RESULTS?

A. Yes, for the most part, DEP's proposed class revenue allocation, based on its CCOSS, is directionally appropriate. In general, a class that is producing a RROR less than 100 should receive an above-average base rate increase (excluding clauses), while a class that is producing a RROR greater than 100 should receive a below-average base rate increase.

As can be seen in **Table 3**, based on the percentage increases without cost recovery clause revenues, including fuel, DEP is proposing above-average base rate increases to those classes currently producing below-average rates of return (*i.e.,* Residential, SGS, Traffic Signal) and below-average base rate increases to those classes currently producing above-average rates of return (*i.e.,* Medium General Service, Seasonal/Intermittent, Area Lighting, Sports Field Lighting).

Table 3
Proposed Base Rate Increase Excluding Cost Recovery Clauses and Restated CCOSS Results Versus The System Average

Customer Class	Increase	Restated CCOSS
Residential	Above Avg.	Below Avg.
Small General Service	Above Avg.	Below Avg.
Medium General Service	Below Avg.	Above Avg.
Large General Service	Above Avg.	Above Avg.
Seasonal/Intermittent	Below Avg.	Above Avg.
Traffic Signal	Above Avg.	Below Avg.
Area Lighting	Below Avg.	Above Avg.
Street Lighting	Below Avg.	Below Avg.
Sports Field Lighting	Decrease	Above Avg.

The only exceptions are with Street Lighting (*i.e.,* Below-Average increase/Below-Average return) and Large General Service (*i.e.,* Above-Average increase/Above-Average return). As previously explained, if the CCOSS is corrected to properly recognize curtailable service, the LGS class would be earning an above-average return, and, in order to move the LGS class closer to cost, it should receive a below-average base rate increase.

Q. IF THE COMMISSION AUTHORIZES A LOWER BASE RATE INCREASE THAN DEP IS PROPOSING, HOW SHOULD THAT LOWER BASE RATE INCREASE BE SPREAD AMONG THE CUSTOMER CLASSES?

A. If the Commission authorizes a lower base rate increase than DEP is proposing, I recommend that DEP's proposed class revenue allocation be scaled down proportionally. For example, if DEP receives 50% of its request, the proposed increases for the major customer classes should be scaled back by 50%. If the CCOSS is modified in this case as I recommend in order to properly reflect curtailable load, it would make sense to provide a larger scale back of the proposed LGS class increase to reflect the lower cost of service.

As for the rate schedules within the customer classes, as previously mentioned and discussed in detail in Part 5, I recommend that each of the LGS rate schedules in this case should receive the same percentage revenue increase as the LGS class (based on the percentage base rate increase, excluding fuel).

5. LGS RATE DESIGN

Q. WHAT IS RATE DESIGN?

A. Rate design is the continuation of the cost allocation process that determines the specific charges within each rate schedule.

Q. WHAT RATE DESIGN ISSUES WILL YOU ADDRESS?

A. Since Nucor is an industrial customer in the LGS class, I will address the design of the rates applicable to the LGS class. The applicable rates include Schedule LGS, Schedule LGS-TOU, and Schedule LGS-CUR-TOU.

Q. IS DEP PROPOSING SIMILAR PERCENTAGE REVENUE CHANGES TO ALL LGS RATES?

A. No. DEP is proposing a 16.9% increase in LGS class rates (exclusive of fuel and other clause revenues). However, the distribution of that increase varies widely within the LGS class. This is shown in **Table 4**.

Table 4
Proposed LGS Net Base Rate Increase Excluding Rider 39 (Fuel) and Other Cost Recovery Clauses

Rate	Amount ($000)	Percent
LGS	$4,651	14.6%
LGS-TOU	$4,601	17.0%
LGS-CUR-TOU	$3,081	22.4%
Total LGS	$12,333	16.9%

As **Table 4** demonstrates, DEP's proposed LGS increase, excluding fuel and other clause revenues, would range from 14.6% to 22.4% depending on the rate schedule. The disparate increases between rate schedules in the LGS class are unwarranted.

Q. WHAT DO YOU RECOMMEND?

A. I recommend continuing the current rate design embodied in the various LGS rate schedules, which appears to have worked satisfactorily for many years. The percentage increase in revenues allocated to Schedule LGS (ideally reflecting only base rates with no clause or fuel revenues) should be applied equally to each of the three LGS rate schedules. In this case, the reasonable, conservative and equitable approach would be to maintain the current status quo as to the relative rate relationships among the three LGS schedules – there is simply no good reason to apply different percentage increases to each of the LGS rate schedules.

6. DEPRECIATION EXPENSE

Q. IS DEP PROPOSING TO IMPLEMENT ANY CHANGE IN DEPRECIATION RATES IN THIS PROCEEDING?

A. Yes. DEP is proposing to implement new depreciation rates in this rate case. The new rates were based on a depreciation study that DEP filed in Docket No. 2018-204-E. This study was previously filed with the North Carolina Utilities Commission. According to DEP, the effect of the depreciation rate change is substantial – it will increase South Carolina revenue requirements by $6 million, roughly 10% of the proposed increase.

Q. WHAT APPROVALS DID DEP SEEK IN DOCKET NO. 2018-204-E?

A. DEP sought approval of an accounting order to adopt new depreciation rates. DEP also requested approval of its depreciation study without notice or hearing.

Q. DID THE COMMISSION APPROVE THE ACCOUNTING ORDER?

A. Yes. The new depreciation rates were approved.

Q. DID APPROVAL OF THE ACCOUNTING ORDER HAVE ANY IMPACT ON RATES?

A. No.

Q. DOES THE ACCOUNTING ORDER PRECLUDE ANY REVIEW OR CHALLENGE OF THE NEW DEPRECIATION RATES IN THIS PROCEEDING?

A. No. The Accounting Order states:

> Under the new depreciation rates, DEP's depreciation expenses for South Carolina will increase by approximately $6.6 million annually, however, there will be no impact on current rates and charges for DEP's customers in South Carolina….This ruling does not preclude the Commission or any party from

addressing the reasonableness of the [depreciation] rates in a subsequent rate case or other proceeding.[8]

Hence, depreciation rates are at issue in this proceeding.

Q. DO YOU HAVE ANY CONCERNS WITH THE DEPRECIATION RATES DERIVED FROM DEP'S DEPRECIATION STUDY?

A. Yes. I am concerned with increasing revenue requirements by $6 million to reflect new depreciation rates, while ignoring the fact that DEP has accumulated a $146.9 million surplus depreciation reserve. The depreciation surplus is shown in **Pollock Exhibit 2** and is summarized in **Table 5** below.

Table 5
Depreciation Reserve Surplus and Annual Accruals
South Carolina Jurisdiction
($ Millions)

Function	Reserve Surplus	Proposed Accrual	Years of Accruals	Average Remaining Life
Steam Production	$26.8	$13.7	2.0	14.3
Nuclear Production	$40.3	$20.8	1.9	19.7
Other Production	($21.3)	$12.9	-1.6	24.2
Hydraulic Production	($1.1)	$0.4	-2.6	19.7
Total Production	$44.8	$47.7	0.9	18.2
Transmission	$14.6	$4.2	3.4	47.3
Distribution	$89.3	$17.9	5.0	29.8
General	($1.7)	$3.3	-0.5	10.7
Total	$146.9			

[8] *IN RE: Petition of Duke Energy Progress, LLC for an Accounting Order to Adopt New Depreciation Rates Effective March 16, 2018,* Docket No. 2018-204-E, ORDER APPROVING ACCOUNTING ORDER TO ADOPT NEW DEPRECIATION RATES at 3 (Aug. 2, 2018).

As **Table 5** demonstrates, most of the surplus reserve is with the distribution accounts ($89.3 million). There is also a $14.6 million surplus in the transmission accounts. The steam and nuclear production accounts have a $67.1 million surplus. These surpluses are equivalent to annual depreciation accruals of five years, over three years, and two years, respectively.

Q. SHOULD DEP'S PROPOSED DEPRECIATION RATES BE REVISED?

A. Yes. DEP's proposed depreciation rates do little to reduce the $146.9 million surplus accumulated in the steam production, transmission, and distribution functions accounts. Eliminating these surpluses over the average remaining lives of these assets would take between 14 and over 47 years. As explained later, the presence of a large depreciation surplus is contrary to the definition of depreciation, which is the recovery of an investment ratably (*i.e.,* equally) over its service life to ensure that both present and future customers are treated equitably; that is, they pay only for the portion of the facilities that is used to provide electric service.

Q. WHAT IS THE SIGNIFICANCE OF DEP'S DEPRECIATION RESERVE SURPLUS?

A. A depreciation surplus means that past and current customers are subsidizing future customers. In other words, there is intergenerational inequity.

Q. HOW CAN INTERGENERATIONAL INEQUITY BE MITIGATED?

A. Intergenerational inequity can be mitigated by amortizing a large depreciation reserve surplus over a much shorter time period than the proposed remaining lives of the assets. While this would not entirely correct past overpayments or track exactly those who overpaid, it will at least return excess collections and achieve balance more quickly while some of the customers who overpaid are still around.

Q. IS AMORTIZING A DEPRECIATION SURPLUS OVER A SHORT TIME PERIOD CONSISTENT WITH ACCEPTED RATEMAKING PRACTICE AND PRECEDENT?

A. Yes, as discussed later, amortizing surplus depreciation is consistent with accepted regulatory accounting practice and precedent. When properly implemented, it does not violate generally accepted accounting principles.

<u>Background</u>

Q. WHAT IS DEPRECIATION?

A. Depreciation reflects the consumption or use of assets used to provide utility service. Thus, it provides for capital recovery of a utility's original investment. Generally, this capital recovery occurs over the average service life of the investment or assets. The most commonly used definition of depreciation is found in the Code of Federal Regulations (CFR):

> Depreciation, as applied to depreciable electric plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities.[9]

[9] 18 CFR Part 101.

In addition, the American Institute of Certified Public Accountants in Accounting Research and Terminology Bulletin #1 provides the following definition of depreciation accounting:

> Depreciation accounting is a system of accounting which aims to distribute cost or other basic value of tangible capital assets, less salvage (if any), over the estimated useful life of the unit (which may be a group of assets) in a systematic and rational manner. It is a process of allocation, not of valuation. Depreciation for the year is the portion of the total charge under such a system that is allocated to the year. Although the allocation may properly take into account occurrences during the year, it is not intended to be a measurement of the effect of all such occurrences.[10]

This definition recognizes depreciation as an allocation of cost to particular accounting periods over the life of assets.

Q. WHAT ARE THE KEY PARAMETERS THAT DETERMINE THE AMOUNT OF DEPRECIATION RECOGNIZED FOR RATEMAKING PURPOSES?

A. Depreciation accounting provides for the recovery of the original cost of an asset over its life. As a result, it is critical that an appropriate average life be used to develop the depreciation rates so that present and future customers are treated equitably. In addition to the recovery of the original cost, depreciation rates also contain a provision for net salvage. Net salvage is the value of the scrap or reused materials less the cost of removing the asset being depreciated. A utility will reflect in its rates the net salvage over the useful life of the asset.

[10] National Association of Regulatory Utility Commissioners (NARUC), *Public Utility Depreciation Practices* at 14 (Aug. 1996).

Q. HOW ARE DEPRECIATION RATES CALCULATED?

A. Depreciation rates are calculated using the straight-line method. DEP uses the remaining life technique to calculate the depreciation rates. Remaining life depreciation rates are derived using the following formula:

$$Remaining\ Life\ Rate = \frac{100\%\ - Reserve\ \% - Avg.Future\ Net\ Salvage\ \%}{Avg.Remaining\ Life\ in\ Years}$$

Under this method of developing depreciation rates, the un-depreciated portion of the plant in service, adjusted for net salvage, is recovered over the average remaining life of the asset or group of assets. Therefore, at the end of the useful life, the asset is fully depreciated.

<u>Surplus Depreciation Reserve</u>

Q. HOW DID YOU QUANTIFY THE AMOUNT OF THE SURPLUS DEPRECIATION RESERVE?

A. The depreciation surplus shown in **Pollock Exhibit 2** was derived from DEP's depreciation study.[11]

DEP's depreciation study was based on December 31, 2016, plant balances. The depreciation reserve surplus shown in **Pollock Exhibit 2** (column 3) is the difference in the book reserve (column 2) and the calculated accrued depreciation (*i.e.,* theoretical reserve), which is shown in column 1. If the book reserve amount is greater than the theoretical reserve a reserve surplus exists. Conversely, if the book reserve amount is less than the theoretical reserve, a reserve deficiency exists.

[11] Direct Testimony of David L. Doss, Jr., Doss Exhibit 2b.

Summing the total book reserves and theoretical reserves for all accounts reveals DEP has accrued a $1,327 million surplus (**Pollock Exhibit 2**, column 3). This equates to $146.9 million (column 6) from South Carolina. In other words, based on DEP's proposed average and the remaining service lives of its investments, DEP's book depreciation reserve is $146.9 million more than the "required" or "theoretical" reserve that its own study shows would be appropriate.

Column 7 shows the proposed future test period accrual for each function, and Column 8 shows the years of accruals associated with the surplus reserve. The steam production and distribution surplus reserves represent multiple years of accruals.

Q. WHAT IS THE THEORETICAL RESERVE?

A. The theoretical reserve is the amount of accumulated depreciation that would have been accrued given the current asset life and net removal cost assumptions employed in DEP's depreciation study.

Q. WHAT IS THE SIGNIFICANCE OF COMPARING THE THEORETICAL AND BOOK DEPRECIATION RESERVES?

A. The purpose of depreciation is to recover capital investment, including removal costs. Such recovery should, to the extent possible, come from the customers that use the utility service. Comparing the theoretical reserve to the book reserve is a useful indicator to determine if the utility is appropriately recovering its capital investment ratably over the projected service life. A large depreciation surplus indicates that the previous and/or current generation of ratepayers has paid a disproportionate share of the assets consumed to provide utility services. This would result in subsidizing the service provided to future generations of ratepayers. Intergenerational subsidies are neither fair nor equitable.

Q. HOW CAN INTERGENERATIONAL EQUITY BE RESTORED?

A. Intergenerational equity can be restored by amortizing a large depreciation reserve surplus over a much shorter time period than the assets' proposed remaining lives.

Q. SHOULD THERE BE ANY DISPUTE OVER THE AMOUNT OF THE DEPRECIATION RESERVE SURPLUS FOR STEAM PRODUCTION AND DISTRIBUTION PLANT?

A. No. The theoretical reserve calculations are based on DEP's proposed depreciation parameters. Thus, the $146.9 million depreciation surplus is based on DEP's proposed life and net salvage parameters. If lives were understated or the net salvage values overstated, the surplus would be higher.

Recommendation

Q. SHOULD THE COMMISSION ADDRESS DEP'S DEPRECIATION SURPLUS?

A. Yes. The $146.9 million surplus depreciation reserves for certain electric accounts should be addressed now — particularly since DEP is also proposing to adjust depreciation rates in this case. With DEP's current customers facing significant rate increases, in part due to changes in depreciation rates, the Commission should require DEP to amortize and return its depreciation reserve surplus over a reasonable period. This will help mitigate the rate increase as well and work toward restoring intergenerational equity.

Q. OVER WHAT PERIOD SHOULD THE DEPRECIATION SURPLUS BE AMORTIZED?

A. Based on the magnitude of the surplus and practices in other states that have also used surplus depreciation to offset a revenue deficiency, I recommend not longer than a ten-year amortization of the depreciation surplus.

Q. HOW WOULD AMORTIZING A $146.9 MILLION DEPRECIATION SURPLUS IMPACT DEP'S OVERALL REVENUE REQUIREMENT?

A. First, it would reduce test-year depreciation expense by $14.7 million (South Carolina Jurisdiction). The derivation of the $14.7 million is shown in **Pollock Exhibit 3**.

Second, amortizing a $146.9 million depreciation surplus would necessitate a corresponding increase in the accrual rates. This is because when the theoretical reserve is used instead of the book reserve in the rate calculation, there is more investment to be depreciated over the remaining life. This impact is shown on **Pollock Exhibit 4**. Specifically, the forecasted test-year accruals were determined using depreciation rates recalculated using the theoretical reserve values. The accruals calculated using the theoretical reserves are shown in column 4. The accruals using the actual reserve amounts are shown in column 5. As can be seen, amortizing the $146.9 million surplus would require increasing the accrual rates, thereby increasing depreciation expense by $5.8 million (line 9, column 6).

Third, the net change in test-year depreciation expense would increase net plant in service. Higher net plant means a higher return on investment. The revenue requirement impact of higher net plant is calculated in **Pollock Exhibit 3**. As can be seen, the net reduction in depreciation expense calculated would increase net plant by $14.7 million (line 3). Applying DEP's proposed rate of return (line 4) and tax conversion factor (line 5) would translate into additional revenue requirement of $1.5

million (line 6).

Thus, the net impact of amortizing a $146.9 million depreciation surplus would be to reduce DEP's proposed revenue requirement by $7.5 million (line 8).

Q. WHAT WOULD BE THE CONSEQUENCE OF ALLOWING THE SURPLUS TO SELF-CORRECT OVER THE NEXT 14 TO OVER 47 YEARS?

A. Without a mid-course correction, the current generation of customers will have paid more for the investment than is required to provide electricity service. Likewise, future customers would underpay for the investment used to provide service. Thus, the consequence would be to force current customers to subsidize future ones, thereby perpetuating intergenerational inequity.

Q. WOULD YOUR PROPOSED MID-COURSE CORRECTION VIOLATE STRAIGHT-LINE DEPRECIATION?

A. No. The affected assets would continue to be depreciated on a straight-line basis, albeit at a lower rate, for the next ten years. This is illustrated in **Pollock Exhibit 5**.

Q. PLEASE EXPLAIN POLLOCK EXHIBIT 5.

A. **Pollock Exhibit 5** illustrates how amortizing a depreciation surplus would restore intergenerational equity. The illustration is based on a $100 asset that is initially assumed to have a 20-year life span. Ignoring removal costs and salvage, annual depreciation expense would be $5 as shown in **Pollock Exhibit 5**, page 1. In year 10, the utility has accumulated a $50 depreciation reserve. However, it then determines that the remaining life of the asset is 30 years. Thus, the theoretical reserve is $33.30 thereby resulting in a $16.70 surplus, as shown in **Pollock Exhibit 5**, page 2.

Let's assume that a mid-course correction is made beginning in Year 11 by amortizing the depreciation surplus over five years. This is shown in **Pollock Exhibit 5**, page 3. As can be seen, annual depreciation expense would be zero in years 11-15. Thereafter, the annual expense would increase to $3.30 for years 16-30. More importantly, as shown on lines 26 and 27, by implementing the mid-course correction, customers in years 1-15 would pay the same amount for the asset as customers in years 16-30. In other words, there would be intergenerational equity.

This would not occur under the remaining life method, as shown in **Pollock Exhibit 5**, page 4. As can be seen, customers in years 1-15 would pay two-thirds of the cost, while customers in years 16-30 would pay only one-third of the cost. In other words, the remaining life method would not result in a systematic and rational allocation.

Q. IS AMORTIZING A SURPLUS DEPRECIATION RESERVE AN ACCEPTED PRACTICE?

A. Yes. The NARUC Public Utility Depreciation Practices Manual states:

> The use of an annual amortization over a short period of time or the setting of depreciation rates using the remaining life technique are two of the most common options for eliminating the imbalance.[12]

As previously stated, the remaining life method would not correct the surplus for 14 to over 47 years. Thus, the remaining life method will not provide either a timely or an adequate remedy to the intergenerational inequity created by DEP's large depreciation

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[12] NARUC, *Public Utility Depreciation Practices August 1996* at 189.

surplus. For this reason, an annual amortization over a short time period would be the more appropriate measure to restore intergenerational equity.

Q. IS THERE ANY PRECEDENT FOR REQUIRING A UTILITY TO USE ITS SURPLUS DEPRECIATION RESERVE TO MITIGATE A RATE INCREASE?

A. Yes. The same technique was proposed by Georgia Power Company (GPC) and approved by the Georgia Public Service Commission (GPSC) to bring GPC's 2009 and 2010 earnings to within the earnings band approved in its 2007 rate case.[13]

The Florida Public Service Commission (FPSC) adopted the same recommendation in the most recent rate cases involving Florida Power & Light Company (FPL) and Progress Energy Florida (PEF).[14] Specifically, FPL was ordered to use a $1.2 billion surplus to offset unrecovered capital costs and to amortize the remaining surplus over four years. PEF was ordered to amortize a portion of its $690 million surplus reserve. In both cases, the objective was to negate large base rate increases. In its Order in the FPL case, the FPSC stated:

> In conclusion, each account's book reserve shall be brought to its calculated theoretically correct level. Of the $1,208.8 million bottom-line reserve surplus, $314.2 million shall be used to offset the unrecovered costs associated with the capital recovery schedules of near-term retiring investments. The remaining

[13] *Georgia Power Company Request for an Accounting Order to Amortize a Portion of Its Regulatory Liability for Accrued Removal Costs*, Docket No. 25060, Order Adopting Stipulation.

[14] Progress Energy was merged into Duke Power. The successor company is named Duke Energy Florida.

> reserve surplus of $894.6 million shall be amortized over a 4-year period, beginning January 1, 2010. [15]

The FPSC's Order in the PEF case stated:

> Balancing the need to correct the reserve surplus with concerns regarding reduced cash flow and financial integrity, we find that $23 million of the reserve surplus shall be amortized over four years in the annual amount of $5,840,613, thereby bringing the increase in annual revenue requirement to zero. The remaining $667 million reserve surplus shall be recovered through the remaining life rate design.[16]

The Minnesota Public Utilities Commission approved an eight-year amortization of a $265 million surplus depreciation reserve for Northern States Power (NSP).[17] The Alabama Public Service Commission voted to use a surplus in Alabama Power Company's cost of removal reserve to offset a $142 million under-collection under Rate CNP-B (Certified New Plant: Purchased Power).[18]

Q. HOW DID PROGRESS ENERGY FLORIDA MAKE USE OF ITS REMAINING RESERVE SURPLUS?

A. In 2010, the FPSC approved a Stipulation and Settlement Agreement that requires PEF to maintain the currently approved base rates. To accomplish this, PEF was allowed discretion to use the remaining surplus by reducing depreciation expense by up to $150

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[15] *In re: Petition For Increase In Rates By Florida Power & Light Company*, Docket No. 080677-EI, Order No. PSC-10-0153-FOF-EI at 87.

[16] *In re: Petition For Increase In Rates By Progress Energy Florida, Inc*., Docket No. 090079-EI, Order No. PSC-10-0131-FOF-EI at 52.

[17] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*; Docket No. E-002/GR-12-961, Findings of Fact, Conclusions and Order at 26, 28-29 (Sept. 3, 2013).

[18] Alabama Power Company, Docket No. U-5208, Order (Feb. 17, 2017).

million in 2010, up to $250 million in 2011, and up to any remaining balance in 2012 until the earlier of when the surplus reaches zero or the term of the Agreement expires.[19]

Q. IS DEP'S SURPLUS DEPRECIATION RESERVE COMPARABLE IN MAGNITUDE TO NORTHERN STATES POWER, FLORIDA POWER & LIGHT AND PROGRESS ENERGY FLORIDA?

A. Yes. The size of DEP's depreciation surplus is comparable to NSP, FPL and PEF, as shown in **Table 6** below.

Table 6
Surplus Reserve Depreciation
(Dollars in Millions)

Description	DEP*	NSP	FPL	PEF
Accumulated Book Depreciation	$10,413	$3,846	$10,915	$4,529
Theoretical Depreciation	$9,085	$3,251	$9,669	$3,740
Reserve Surplus	$1,327	$595	$1,246	$789
Surplus as a % of Book Depreciation	13%	15%	11%	17%

*** Includes all depreciable plant accounts included in depreciation study.**

[19] *In re: Petition For Increase In Rates By Progress Energy Florida, Inc*. Docket No. 090079-EI, *In re: Petition For Limited Proceeding To Include Bartow Repowering Project In Base Rates, By Progress Energy Florida, Inc*., Docket No. 090144-EI, *In re: Petition For Expedited Approval Of The Deferral Of Pension Expenses, Authorization To Charge Storm Hardening Expenses To The Storm Damage Reserve, And Variance From Or Waiver Of Rule 25-6.0143(1)(c), (d), and (f), F.A.C., by Progress Energy Florida, Inc*., Docket No. 090145-EI; *In re: Petition for Approval of an Accounting Order to Record a Depreciation Expense Credit , by Progress Energy Florida, Inc.,* Docket No. 100136-EI, Order No. PSC-10-0398-S-EI, Order Approving Stipulation and Settlement, Att. 1 at 3 (Jun. 18, 2010).

Thus, intergenerational inequity is as serious a problem with DEP as it was for NSP, FPL, and PEF. This justifies similar immediate action to restore intergenerational equity and to help mitigate the impact of both pending and future base rate increases.

Q. DO THE ALABAMA, FLORIDA, GEORGIA AND MINNESOTA COMMISSIONS USE THE REMAINING LIFE METHOD IN SETTING DEPRECIATION RATES FOR THE UTILITIES THAT THEY REGULATE?

A. Yes.

Q. WHY ELSE SHOULD DEP'S LARGE DEPRECIATION SURPLUS BE AMORTIZED IN THIS CASE?

A. As was the case in Alabama, Georgia, Florida and Minnesota, a depreciation surplus can be used to mitigate rate increases, such as DEP is proposing in this case. Further, it is consistent with setting rates that are just and reasonable and reflect a utility's cost of service. And finally, using surplus depreciation is not a disallowance. DEP will continue to have a reasonable opportunity to recover its used and useful investment. The only difference is that there will be better timing of cost recovery and a better matching between cost recovery and the customers utilizing electricity service.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION ON DEPRECIATION EXPENSE.

A. Consistent with accepted practice and precedent, the Commission should lower DEP's test-year revenue requirement by $7.5 million to amortize a $146.9 million accumulated depreciation reserve surplus over ten years. Not only would this help to mitigate DEP's proposed rate increase, it would also restore intergenerational equity.

7. CONCLUSION

Q. BASED ON YOUR RECOMMENDATIONS, WHAT FINDINGS SHOULD THE COMMISSION MAKE?

A. The Commission should make the following findings:

- Reduce DEP's proposed revenue increase by half based on specific adjustments I and Ms. LaConte have proposed, before considering DEP's proposed return on common equity and common equity ratio.
- Order DEP to revise its CCOSS in this case or, at a minimum, in its next rate case to appropriately recognize the non-firm service provided to its curtailable customers by allocating capacity costs to classes based on firm peak demand.
- Approve the same percentage increase for all LGS rate schedules, where the increase is measured excluding fuel and all other cost recovery clauses.
- Order DEP to present its proposed percentage base rate increases in future cases excluding revenues from fuel and all other cost recovery clauses.
- Order DEP to amortize and return to consumers a $146.9 million depreciation reserve surplus over a period not exceeding ten years.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

APPENDIX A

PROCEDURES FOR CONDUCTING A CLASS COST-OF-SERVICE STUDY

Q. WHAT PROCEDURES ARE USED IN A COST-OF-SERVICE STUDY?

A. The basic procedure for conducting a class cost-of-service study is a three-step process. First, we identify the different types of costs (functionalization), determine their primary causative factors (classification), and then apportion each item of cost among the various rate classes (allocation). Adding up the individual pieces gives the total cost for each class.

Identifying the utility's different levels of operation is a process referred to as functionalization. The utility's investments and expenses are separated into production, transmission, distribution, and other functions. To a large extent, this is done in accordance with the Uniform System of Accounts developed by the Federal Energy Regulatory Commission (FERC).

Once costs have been functionalized, the next step is to identify the primary causative factor (or factors). This step is referred to as classification. Costs are classified as demand-related, energy-related or customer-related. Demand (or capacity) related costs vary with peak demand, which is measured in kilowatts (or kW). This includes production, transmission, and some distribution investment and related fixed O&M expenses. As explained later, peak demand determines the amount of capacity needed for reliable service. Energy-related costs vary with the production of energy, which is measured in kilowatt-hours (or kWh). Energy-related costs include fuel and variable O&M expense. Customer-related costs vary directly with the number of customers and include expenses such as meters, service drops, billing, and customer service.

Each functionalized and classified cost must then be allocated to the various customer classes. This is accomplished by developing allocation factors that reflect the percentage of the total cost that should be paid by each class. The allocation factors should reflect cost causation; that is, the degree to which each class caused the utility to incur the cost.

Q. WHAT KEY PRINCIPLES ARE RECOGNIZED IN A CLASS COST-OF-SERVICE STUDY?

A. A properly conducted class cost-of-service study recognizes two key cost causation principles. First, customers are served at different delivery voltages. This affects the amount of investment the utility must make to deliver electricity to the meter. Second, since cost causation is also related to how electricity is used, both the timing and rate of energy consumption (*i.e.*, demand) are critical. Because electricity cannot be stored for any significant time period, a utility must acquire sufficient generation resources and construct the required transmission facilities to meet the maximum projected demand (coincident peak), including a reserve margin as a contingency against forced and unforced outages, severe weather, and load forecast error. Customers that use firm electricity and cannot be curtailed during the critical peak hours cause the utility to invest in generation and transmission facilities.

Q. WHAT FACTORS CAUSE THE PER-UNIT COSTS TO DIFFER AMONG CUSTOMER CLASSES?

A. Factors that affect the per-unit cost include whether a customer's usage is constant or fluctuating, whether the utility must invest in transformers and distribution systems to provide the electricity at lower voltage levels, the amount of electricity that a customer uses, the quality of service (*e.g.,* firm or non-firm). In general, industrial consumers are less costly to serve on a per unit basis because they:

1. Operate at higher load factors;
2. Take service at higher delivery voltages; and
3. Use more electricity per customer.

A customer that purchases non-firm or curtailable/interruptible service is receiving a lower quality of service than firm service. Thus, non-firm service is less costly per unit than firm service for customers that otherwise have the same characteristics.

All of these factors explain why some customers pay lower average rates than others. For example, the per unit cost for losses and the cost of distribution facilities typically become greater the farther down the distribution system the customer receives service.

Two other cost drivers are efficiency and size. These drivers are important because most fixed costs are allocated on either a demand or customer basis.

Efficiency can be measured in terms of load factor. Load factor is the ratio of average demand (*i.e.*, energy usage divided by the number of hours in the period) to peak demand. A customer that operates at a high load factor is more efficient than a lower load factor customer because it requires less capacity for the same amount of energy. For example, assume that two customers purchase the same amount of energy, but one customer has an 80% load factor and the other has a 40% load factor. The 40% load factor customers would have twice the peak demand of the 80% load factor customers, and the utility would therefore require twice as much capacity to serve the 40% load factor customer as the 80% load factor. Stated differently, the fixed costs to serve a high load factor customer are spread over more kWh usage than for a low load factor customer.

APPENDIX B

<u>TREATMENT OF CURTAILABLE LOAD IN A CLASS COST-OF-SERVICE STUDY</u>

Q. HOW SHOULD CURTAILABLE LOAD BE TREATED IN THE CLASS COST-OF-SERVICE STUDY?

A. Capacity costs should be allocated based on firm peak demand and should not be allocated based on curtailable demands because curtailable load does not cause such costs to be incurred. This would be accomplished by excluding curtailable load from the demand allocation factors in the CCOSS, as if the load were curtailed, and the allocation factors would then only reflect firm coincident peak loads (*i.e.,* **Method 1**)

An alternative approach would be to include curtailable load in the CCOSS as if it were firm service for both revenues and costs. Under this alternative, the revenues for the classes containing curtailable load would be increased and restated to equal the revenues that would exist if all of the load were entirely firm (effectively removing the impact of lower non-firm rates and/or curtailable credits attributed to these classes), and the difference between firm and non-firm revenues (referred to as curtailable credits) would be allocated to all customer classes based on firm coincident loads (*i.e.,* **Method 2**).

Either approach would be consistent with cost-causation principles and regulatory precedent. Of course, ***Method 1*** is more straightforward, but it requires DEP to rerun its CCOSS with new demand allocation factors.

Q. HOW WOULD ADJUSTING FOR CURTAILABLE LOAD AFFECT THE RESULTS OF DEP'S CLASS COST-OF-SERVICE STUDY?

A. An illustrative example is provided in **Exhibit B-1**. It assumes that the curtailable credits are equivalent to a $10 million credit relative to the cost to provide firm service.[20]

The illustration is based on ***Method 2*** as described above because we do not have the DEP cost-of-service model. Specifically, I assumed that the LGS class receives $10 million per year in curtailable credits. These credits should be allocated to customer classes based on firm peak demand. I have estimated the firm peak demand allocation factors in **Exhibit B-2**. Using these firm peak demand allocators, I calculated a curtailable adjustment by customer class and calculated the change in each class's net operating income. This calculation is shown in **Exhibit B-1**, lines 1 through 4. The corresponding net operating income at present rates in DEP's CCOSS is shown on line 5. The adjusted net operating income at present rates (line 6) is the sum of the curtailable adjustment net of taxes (line 4) and the net operating income at present rates (line 5). The calculated rate of return (line 8) is the adjusted net operating income (line 6) divided by the allocated rate base (line 7). The corresponding relative rate of return (RROR) shown on line 9 expresses each class's rate of return at present rates (line 8) as a percent of the South Carolina retail average rate of return, which is 4.10%.

[20] DEP currently provides curtailable service to loads in both the SGS and LGS customer classes. However, the vast majority of this load is in the LGS class. Accordingly, the illustration focuses on quantifying the impact on the LGS class.